COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Investigation into Distributed Generation	)	Docket No. DTE 02-38

REPLY COMMENTS OF
MASSACHUSETTS ELECTRIC COMPANY
AND
NANTUCKET ELECTRIC COMPANY

Massachusetts Electric Company and Nantucket Electric Company (together "Mass. Electric" or "Company") submit these reply comments in the Department of Telecommunication and Energy's ("Department's") investigation into distributed generation ("DG") in this docket.

The Department received over thirty sets of initial comments, reflecting the positions of an even greater number of interested parties. Although the comments generally reflect a number of common themes and principles, the wide range of views and positions expressed highlight the complexity of DG issues. In these reply comments, Mass. Electric attempts to identify those areas that may be appropriate for resolution in this proceeding, and those that the Company believes require further consideration before a policy direction is established.

I. Interconnection Standards and Procedures

Most of the commenters support consistent interconnection standards and procedures across the state. *See, e.g.,* National Energy Marketers p. 2; National Association of Energy Service Companies p. 2; United Technologies p. 2; Fitchburg Gas & Electric p. 3; Trigen

Boston Energy p. 2; Keyspan Energy p. 2; Stone & Webster p. 2; and NStar Electric p. 31. No commenter argues against consistent interconnection standards and procedures, although many acknowledge that there could be a specific DG project that could not interconnect with the distribution system using generic interconnection standards and procedures.

Commenters do not agree on what the statewide interconnection standards and procedures should look like, however. Some commenters favor the IEEE draft standards (*see, e.g.*, National Energy Marketers Association p. 2; Ingersoll-Rand p. 5). Some commenters recommend against adopting the IEEE draft standards (*see, e.g.* Fitchburg Gas & Electric p. 4, Aegis Energy p. 3, and RealEnergy, the Joint Supporters, Hess Microgen, Nuvera Fuel Cells, North Battery Development, and Berkshire Development (hereinafter "RealEnergy") p. 10). Other commenters recommend adopting the National Association of Regulatory Utility Commissioners ("NARUC"), California, or Delaware model for DG, and still others favor developing different standards for Massachusetts. *See, e.g.*, Ingersoll-Rand p. 5 (favoring NARUC model as a starting point along with the adoption of the IEEE standards); RealEnergy p. 10 (recommending using California, Texas or Delaware as a model). Some commenters recommend adopting Mass. Electric's current interconnection requirements document, attached as Exhibit 1 to Mass. Electric's initial comments. *See, e.g.*, SEBANE p. 4.

In addition, commenters give different recommendations about size thresholds. For example, MeadWestvaco recommends that small qualifying facilities subject to fast track approval be defined as those 50 MW and below (pp. 4, 15) and Trigen recommends that they be less than 20 MW (p. 1). SEBANE recommends raising the limit for expedited interconnection of solar generators up to 300 kW (p. 7). Commenters also raise many specific concerns regarding the engineering of DG installations and interconnections, the need for interconnection studies, and who must pay for them.

The Massachusetts Technology Park Corporation (d/b/a Massachusetts Technology Collaborative) on behalf of the Renewable Energy Trust ("MTC") and the Attorney General both recommend that the Department initiate a collaborative process to address the issues raised by the Department in its Notice of Investigation. MTC pp. 20-22, Attorney General p. 2. Likewise, the Division of Energy Resources ("DOER") and NAESCO recommend the convening of a collaborative technical proceeding on interconnection issues. DOER p. 4, n.7; NAESCO p. 1. Mass. Electric believes that a collaborative process would be an excellent way for interested stakeholders to work through the details of what the appropriate interconnection standards and procedures should be in the state. As mentioned in Mass. Electric's initial comments, a number of parties have already been working together on the development of common interconnection standards. Mass. Electric pp. 5-6. A broader collaborative process would enable the stakeholders to discuss and consider the issues and develop consensus solutions for interconnection standards and procedures. This process is most likely to lead to interconnection standards and procedures that address the issues in a way that is workable for all of the stakeholders.

That being said, Mass. Electric wishes to address briefly some specific issues raised by commenters. First, Mass. Electric turns to the various recommendations regarding the adoption of various generic standards. Although the IEEE standards are good, as Stone & Webster and others point out, they are too general and will not address all of the issues associated with interconnections. As to the NARUC or California models, Mass. Electric considered these models, as well as the New York and Texas models, when it developed its interconnection requirements document attached as Exhibit 1 in its initial comments. Mass. Electric decided against adopting these models because they were more complicated than Mass. Electric thought necessary. For example, the NARUC and California models require a study of line peak load, which Mass. Electric does not require. The relative level of complexity between the procedures can be seen by comparing Mass. Electric's interconnection flow chart, Exhibit 2 to its initial comments, to the NARUC or California model, which is attached on page 1 of Exhibit 1 hereto. For the Department's convenience, Mass. Electric's interconnection flow chart is also included on page 2 of Exhibit 1.

Second, Mass. Electric notes that many non-utility commenters state that utility interconnection policies are a barrier to widespread DG installation, and recommend that utilities categorize distributed generation by size, type of power source, or whether the proposed site is on a conventional radial distribution feeder or a network distribution system. In fact, Mass. Electric's current interconnection requirements document, recently approved by the Department and attached to Mass. Electric's initial comments as Exhibit 1, already does categorize DG installations by all three of these measures. Mass. Electric believes that its interconnection requirements document addresses many of the commenters' concerns and recognizes that many of the commenters raising these concerns may not be familiar with the Company's interconnection requirements document. The collaborative process could be a forum for (1) educating the public about existing policies and practices, (2) exploring whether interconnections standards and procedures such as those contained in Mass. Electric's interconnection requirements document address the commenters' concerns, and (3) if not, how the interconnection requirements document could be revised to address them.

Third, some commenters suggest that the Department require that the process be simplified for DG systems of 20 MW to 50 MW. A typical 15 kV class distribution feeder has a capacity of less than 10 MW, however. A 20 MW DG unit is more than twice the capacity of such a feeder, and the feeder physically could not carry this much power. Indeed, even a 1 MW DG system on a feeder of this size requires extensive studies and changes to the protection system.[1] A blanket exception of the size requested, therefore, is not prudent. A collaborative would bring together economic and reliability interests to find the optimal middle ground in setting thresholds.

Fourth, SEBANE proposes modifying Mass. Electric's interconnection requirements document to allow the expedited interconnection of solar generators up to 300 kW. Although the protection characteristics of inverters meeting UL 1741 will be the same, as the DG system size goes up, the effect on feeder voltage regulation may become more difficult to manage. Therefore, the Company believes that feeder specific studies are necessary to determine if there might be voltage regulation problems with units this large. Mass. Electric's current interconnection requirements document allows for expedited interconnection of units up to 10 kW that use a UL 1741 listed inverter. Accordingly, Mass. Electric recommends that expedited consideration remain as specified in its interconnection requirements document.

Fifth, some commenters suggest that the Department institute testing and certification of DG units. NAESCO p. 2, Real Energy p.9, Capstone Turbine Corporation p. 4. The Company believes that this would result in additional expense to the DG manufacturer, without a corresponding benefit. National standards, such as UL 1741 for inverters, developed as part

[1] To the extent that the commenters proposing a streamlined process for generating units up to 50 MW that would be interconnecting to the transmission system, such an interconnection process would be pursuant to procedures established by NEPOOL and ISO New England, under the jurisdiction of the Federal Energy Regulatory Commission.

of the IEEE 929-2000 process, provide assurance that a DG product will perform as the manufacturer claims. Adding a state testing and certification requirement would be redundant and wasteful.

Sixth, both SEBANE and Plug Power have commented on Mass. Electric's criterion for DG on network systems. Mass. Electric allows customers to interconnect on its network system without costly reverse-power relaying if the ratio between the customer's minimum load and the DG peak capacity is at least fifteen to one. Mass. Electric's use of this ratio is innovative from an industry standpoint, because it allows hassle-free interconnections of DG on network systems. SEBANE recommends defining the minimum load by special metering between 9:00 a.m. and 5:00 p.m., when solar photovoltaic systems are likely to be generating energy. SEBANE p. 5. Mass. Electric believes that this concept is reasonable, but cautions that it could add costs to the interconnection of all but the largest customers, those on the G-3 rate, due to special metering requirements and reviews. Therefore, Mass. Electric recommends against adopting SEBANE's proposal, unless the customer requesting the study also is responsible for the cost. Plug Power recommends that the load-to-peak DG capacity ratio be lowered to four-to-one. Network distribution system present complex technical issues that do not exist in typical radial configurations. Mass. Electric believes that a lower ratio poses risks to the quality of network distribution service and does not recommend its adoption absent further engineering analysis and experience demonstrating that such a ratio is acceptable.

It also is important to recognize that consistent and appropriate interconnection standards will not necessarily address all of the concerns of some customers with specific power requirements or system configurations. Distribution utility interconnection policies are designed to protect utility equipment, employees and customers, and to maintain the quality of service on the distribution system. Wyeth Biopharma noted that distribution system disturbances can affect the operation of its generation unit, causing it to shutdown and requiring the customer to take service from the distribution system. Normal distribution system activities that are necessary under good utility practice to ensure reliable service to customers may cause disturbances on the electric grid of such minor duration and magnitude that the vast majority of customers are unaffected. However, it is possible that some customers, including DG customers, may be affected by otherwise minor system disturbances.[2]

Therefore, the success of DG depends, in part, upon the customer's own site-specific interconnection needs. For example, DG customers that need near perfect power quality must have an interconnection that allows exceptional power quality. Such an interconnection would likely be more than what would be required by the local distribution utility under its typical standards. However, as the MTC noted, most DG customers are not in the generation business. MTC p. 17. Thus, DG customers may be unaware or skeptical if a distribution utility recommends that the customer study or install costly protection schemes against system disturbances in order to meet the customer's power quality requirements. As a result, some customers that install DG may in fact end up with facilities that are more susceptible to power quality disturbances than customers without DG, even if one of the reasons they sought to install DG in the first place was to enhance power quality. In order to prevent unwanted outages of DG systems, additional equipment must be installed on the customer's side of the interconnection in order to withstand system disturbances. This is equivalent to the equipment that many critical customers, including for example financial institutions, use in order to ensure uninterrupted power. Customers must understand these issues when considering DG.

In conclusion, the Company believes that its interconnection requirements document fulfills many of the commenters' recommendations. The Company's interconnection requirements document is an aggressive attempt to simplify the interconnection process as much as possible based on current experience and technology. With reliability a primary concern for customers, the Company, and the Department, Mass. Electric recommends that the Department proceed cautiously with more aggressive changes. Instead, the electric industry needs to obtain more experience with DG in order to simplify and expedite the process on the one hand and maintain acceptable reliability to all customers on the other. A collaborative process is well suited to explore these issues.

II. Standby Rates for Distributed Generation

Practically every one of the commenters in this docket submitted comments on the desired design of standby service tariffs for DG. While the range of positions is quite broad, there are a number of common themes that run throughout most of the comments, including:

- *Standby rates should be cost-based; See, e.g.,* NAESCO p. 3; Solutia p. 1; AES New Energy p. 5,
- *Standby rates should not result in undue cost shifting or cross subsidies from other customers;* See *e.g.*, AES New Energy p. 3; MASSCAP p. 3; Fitchburg Gas & Electric p. 5,
- *Standby rates should provide DG customers with a range of options for the level and quality of service they desire, and should be priced accordingly; See, e.g.,* E-Cubed p. 3; NECA p. 5; AES New Energy p. 2, *and*
- *DG rates should reflect whether the installation provides system benefits, or imposes additional system costs. See, e.g.*, Ingersoll-Rand p. 5; Stone & Webster p. 3; United Technologies pp. 4-5.

[2] For example, a DG customer's generation will be designed to trip off when there is a fault on the transmission or distribution system to prevent the DG from feeding fault current into a fault and to prevent damage to the DG unit, which might otherwise try to pick up all the load in the area.

Mass. Electric generally agrees with these principles. As the Company stated in its initial comments, rates for service to DG customers "should fairly apportion and recover costs imposed (or benefits conferred) on the distribution system from the users of the system, should not encourage wasteful or uneconomic decisions, and should prevent undue cost shifting among customer classes." Mass. Electric p. 8. Mass. Electric believes that the rate design described in its initial comments is consistent with the common themes noted above. In addition, it is clear from the comments that the development of a standby rate will provide certainty to customers considering DG and enable them to make informed decisions regarding the economics of installing DG.

If a customer wants 100 percent instantaneous and seamless standby service in the event of a loss of on-site generation, Mass. Electric proposes a full cost-based distribution rate for the customer's total distribution service needs, both actual delivered and generated capacity and energy. This customer is, in essence, requesting that Mass. Electric reserve capacity for 100 percent of its potential maximum load and energy delivery and provides access to electricity at any time without restrictions. The standby rates should reflect the nature of this requested service. A rate design that charges full distribution rates for delivered and generated energy assures that the customer is fairly contributing to the costs of the distribution system in the same manner as any other customer that relies on the distribution system to deliver 100 percent of its usage.

The distribution system is built to meet maximum demands imposed on it by customers. Distribution rates are designed for all customer classes in a way that fairly allocates costs among customer groups and equitably shares the diversity benefit of customer's actual demands during peak conditions throughout the distribution system. By charging a customer for its actual delivery and generation output, the Company treats equally all customers that can use the system the same amount of hours during the year.

On the other hand, a customer with self-generation that does not require 100 percent backup service, or is willing to limit its backup service requirements to off-peak periods, might not impose the same potential demands on the distribution system as a 100 percent backup service customer. In that case, the distribution company's costs of serving such a customer might be reduced.[3] The distribution utility also might determine alternative uses for the distribution capacity that is not used by a "partial requirements" standby customer. In such cases, the standby rates or billing units for customers with limited or reduced backup requirements could be discounted from the full service standby rates. Discounted standby rates or billing units for service with controlled access to the distribution system would encourage customers with DG to provide real benefits to the system by removing load from the system during peak conditions, would reflect the fact that DG customers have options that are not available to other customers with respect to use of the distribution system, and would provide for appropriate distribution system cost recovery. [4]

While the proposed rate design described above provides an alternative standby rate design, as desired by many of the commentators, there are other designs that also can achieve the rate design objectives associated with DG. *See, e.g.*, Mass. Electric (p 14, n. 6, citing filed standby tariffs for utilities throughout the country). Rather than establish a single rate design for backup or standby service, it may be more appropriate to provide customers with on-site

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[3] One simple analogy might be a typical insurance policy. In general, the greater the level of deductible a customer is willing to accept for an insurance policy, the less likely the customer is to make a claim against the policy and the lower the level of premium paid for that policy. Conversely, the smaller the deductible on a policy, the greater the likelihood of a claim on that policy and therefore the greater the premium. In addition, insurance policy charges may be increased above average due to specific conditions relative to the nature of the insured.

[4]As noted in its initial comments, Mass. Electric is required under its Rate Plan Settlement in Docket D.T.E. 99-47, to file a new Auxiliary Service proposal once the level of new customer-owned generating capacity (since July 1, 1999, and subject to certain qualifications) exceeds 15MW. Among other things, the Settlement provides that Mass. Electric's proposed Auxiliary Service rates "will be designed to recoup the

generation a menu of backup service options that provide varying degrees of economic incentive to the customer while at the same time preventing cross-subsidies among customers with no on-site generation.[5]

A number of commenters set forth other positions or proposals for standby rate designs that are in direct conflict with one or more of the broadly supported common rate design themes discussed above. For example, some commenters suggested that rates for DG customers should be de-averaged, and that such customers should in effect pay a specific, individualized rate for service. *See, e.g.*, Ingersoll-Rand p. 6; United Technologies p. 5. These commenters propose differentiated distribution rates based on such factors as location and type of DG technology.

Mass. Electric supports the concept that it may be appropriate to provide distributed resource customers (e.g., DG or committed load reduction) with individualized or tailored credits to the extent that the deployment of the distributed resource allows the distribution company to reduce costs through investment deferral. The use of site-specific credits targets compensation to customers for benefits produced by a particular distributed resource and reflects the nature, value, and duration of the benefit. The Company does not support, however, the concept of tailoring distribution rates and tariffs for each DG customer. This concept is at odds with the fundamental concept of average cost rate making, would be extremely burdensome to develop and administer, and would result in inequitable and discriminatory cost shifts among customers. This rate design would subject some customers to higher rates and give other customers lower rates by granting customers with DG preferential

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net lost revenues attributable to the subset of customers to which the Auxiliary Service Provisions would apply." Rate Plan Settlement, Docket D.T.E. 99-47, at 12 (Nov. 29, 1999).

[5] Mass. Electric does not propose that a customer with self-generation should pay for reservation of capacity based upon demand ratchets or contract demands. Mass. Electric believes these types of rates could be used in the design of standby rates for distribution service if they are

treatment over similarly situated customers without DG. Customers without DG would reject this rate design.

Other commenters suggest that DG rates should reflect other purported benefits produced by the units. *See, e.g.*, Wyeth BioPharma p. 25(suggesting Department creation of a transmission congestion reduction credit). First, there can be no question that the DG customer is the overwhelming recipient of any benefits produced by the on-site generation. These include the customer's ability to better control its own costs, greater arbitrage options, increased process assurance in the event of a loss of power from the utility, and the use of thermal output in combined heat and power situations. To the extent that a DG solution can provide benefits that reduce distribution costs for other distribution system customers, and those benefits are quantifiable, it may be appropriate to provide some compensation to the DG customer (for example, in the form of credits as the Company is doing with its Brockton Pilot). As mentioned above, however, the Company does not support the development of individualized distribution rates for DG customers. Further, to the extent that the purported benefits of DG are not associated directly with the distribution system (for example, potential transmission congestion cost savings as proposed by Wyeth BioPharma), they would not be relevant for any distribution-based credit unless an opportunity is created for Mass. Electric to receive credits and flow them back to customers.

Another suggestion by some commenters is that distribution rates for DG should be based on the level of reliability of the particular DG technology being used. *See, e.g.*, NECA p. 6; United Technologies p. 7. Again, this cuts against principles of equity and average cost ratemaking. Furthermore, it assumes that the level of reliability for a particular technology

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also applied to all similarly situated customers. If the Department wishes to implement a rate that uses demand ratchets or contract demands, Mass. Electric reserves the right to provide comments to the Department on that rate design at the appropriate time.

will be reflected in the operation of an individual unit, whereas in fact, the performance parameters are much more likely to be affected by site and region-specific influences (e.g., market prices of energy or fuel, plant conditions, maintenance practices, etc.). Unanticipated outages on even the most reliable type of generation technology will still impose significant, instantaneous demands on the distribution system, as described in Mass. Electric's initial comments (pp. 14-16), and illustrated graphically in Exhibit 2 to these reply comments. Exhibit 2 shows the demand profile on the distribution system imposed by an actual DG customer during outage events. As the graphs in Exhibit 2 illustrate, DG outages can occur at any time on any day, including peak hours of high load days, and impose unexpected demands on the distribution system which the system must be prepared to serve.

Lastly, the establishment of rates based on the reliability of a particular technology ignores the new market for electricity: once a customer has invested in generation, the customer's decision is purely economic with respect to whether the customer runs its DG unit or purchases power to be delivered over the distribution system. If the DG resource costs more than the market price for electricity, the customer would make the appropriate economic decision to shut down the generator and receive electricity from the market. This could happen at any time and cause local peaks on the distribution grid. Mass. Electric's affiliate, The Narragansett Electric Company, has a customer that has ceased operation of its generating units in order to take advantage of low prices in electric markets. The fact that the utility generally has no control over the operation of on-site generation further exacerbates the matter.

Many proponents of DG argue that the demand rate structure of present rate designs in Massachusetts is an impediment to the implementation of DG and that this type of rate design does not reflect diversity benefits from DG. The demand rates may be costly to the customer whose unit goes out of service, but they are premised upon many years of Department precedent regarding the recovery of fixed costs to serve customers. The distribution system is designed to meet maximum local peaks of all customers in an area and throughout the system. The system's design allows this capacity to be flexible in many areas when system outages occur in order to restore service to customers quickly while the cause of the initial outage is fixed. Costs are allocated to each rate class based upon the maximum, diversified demands of that rate class, and therefore, diversity of all customer loads within a rate class serves to lower the allocable share of costs to the rate class. Few customers have their peak demand at the time of the rate class maximum demand, but all customers are charged their peak demand in order to recover distribution costs. This method ensures that diversity of customer loads fairly spreads cost responsibility among all customers. Although some customers may perceive charging demand rates as expensive, this rate design fairly and equitably recovers costs of the distribution system, which is designed to provide service at peak demands.

Some commenters suggest that backup service rates should be based on average, rather than peak, usage. MeadWestvaco p.6. As explained above, the distribution system is designed to meet maximum local peaks of all customers in the area and throughout the system. Exhibit 3 also graphically depicts an actual DG customer's maximum daily load on the distribution system compared to its average daily load over the recent year. A system designed to serve the variability demonstrated in daily loads must be more robust, and as a result more expensive, than one designed to serve average usage. Additionally, all customers on demand-based rates pay for distribution service, in part based upon their peak demand on the system during a month. However, costs are not allocated on customer peak demands but on class peak demands. Thus, all customers get the benefit of diversity within the class. Setting rates on an average demand basis would only serve to raise the demand charge, because the distribution company must still recover the same amount of costs, but the billing units have been lowered. Therefore, a backup rate based on average, rather than peak, usage would not be appropriate and would not enable the distribution company to recover its costs.

Still other commenters suggest, with little or no explanation, that net metering should be extended beyond the currently established levels in the Commonwealth and applied to larger installations. Aegis Energy. Other commenters note that net metering for units over a certain size may not be appropriate, however, and any generation credits should be tied to the energy portion of the service only. NECA p. 4. Mass. Electric does not support the broad application of net metering because it results in tremendous cross subsidies and unpaid use of the distribution and transmission systems. The Company nevertheless recognizes that net metering may be appropriate as a means to encourage the development and deployment of certain new and desirable renewable energy technologies. Much like conservation programs, net metering is an incentive to customers to use innovative technologies that have not become economic. Accordingly, Mass. Electric proposes that net metering for any particular technology be discontinued once the technology is economic in the electric marketplace. In addition, net metering should be discontinued if the distribution company has substantial distribution revenue loss from the program. The Company does not support the expansion of net metering beyond already established levels, because to do so would shift focus from the least economic technologies towards more economic facilities that may be successful without the need for net metering. This could create lost opportunities as larger customers take advantage of net metering and force the window of opportunity to close for smaller customers or more developmental technologies.

Mass. Electric next addresses Wyeth Biopharma's assertion that backup and standby rates would result in an unreasonable return on investment for a distribution company if the customer has already compensated the distribution company for its distribution related expenditures through a line extension charge or rates paid over the course of time. Wyeth Biopharma p. 14. Line extension, or construction advance, policies serve to recover investments in distribution facilities to serve the customer if recovery of those investments is not supported by expected customer use at a facility. A customer who invests in DG that assumes minimal downtime for the operation of the unit is more likely to be charged a construction advance if construction is necessary than a similar-sized customer without DG. The construction advance policy allows the customer to request a determination of a potential refund from the company if actual customer use is greater than that estimated within the first three years of operation. The refund provision allows for a fair balancing of risks with the customer, and disagreements about projected use of the distribution system can be kept to a minimum because customers can request a refund within the first three years of operation. Once the construction advance is paid, customers are subject to rates applied to actual use. Thus, customers do not pay twice for any construction. The payments are for separate bundles of distribution system cost.

Other issues raised by commentators relate to the treatment of non-bypassable charges such as stranded costs, DSM charges, low-income charges, and other similar charges. Many of these charges are determined statutorily, and are generally based on usage. If DG users were able to bypass these charges, which have been determined to be for the overall good of the state, other customers would be put in the position of picking up the costs. This would not be appropriate.

Given the broad range of issues and positions, several parties have proposed the establishment of a collaborative process with the objective of narrowing the issues and presenting a specific set of proposals to the DTE, or at the very least narrowing and refining the areas of disagreement. MTC pp. 20-22, Attorney General p. 2. Although Mass. Electric believes that the rate design proposal it offers would achieve appropriate rate design principles and not impair the development of economically efficient DG, the Company nevertheless supports the establishment of a collaborative process designed to further explore the issues of standby rate design for DG. The collaborative could work to develop a consensus standby rate design proposal for the Department, or in the alternative, could develop recommendations regarding standby rates.

III. The Use of Distributed Generation in Distribution System Planning

Commenters had many varied recommendations regarding the role of DG in distribution system planning. First of all, many commenters recommend that distribution companies be required to consider DG in their planning process. Keyspan p. 4, Capstone Turbine Corporation p. 9, Ingersoll Rand p. 6, Real Energy p.16, Cape Light Compact p.4, NAESCO p.4, NEMA p. 4, Plug Power p. 6. As discussed in the Company's initial comments, Mass. Electric already considers the installation of DG each time that it conducts a study of its distribution system. The Company, however, has not gone with a DG solution for a few reasons. There are significant environmental and permitting issues, including emissions problems, lengthy lead times for permitting large DG units, local noise issues, and environmental clean-up concerns. These factors influence the cost of distributed generation, and traditional transmission and distribution solutions have consistently been more cost effective.

Commenters do not agree on the level of availability that DG can provide. Some commenters were concerned that the reliability of DG could not meet the stringent reliability criteria that utilities use currently. Fitchburg Gas & Electric p. 14, NSTAR Electric p.36. Others stressed that differing technologies had differing availability. NE-CHP p. 6, NECA p. 6. To date, DG has not successfully demonstrated availability levels comparable to the reliability of the distribution system. For example, a typical utility feeder has 90 minutes of outages per year, for an availability of 99.983%. In contrast, few vendors of DG systems will suggest that their equipment has availability greater than 99%, or 5,256 minutes (3.6 days) of outages per year.

The Company has not incorporated customer or third party DG in its studies for the reasons set forth in the Company's initial comments. In summary, if the Company does not own the unit, the Company does not control the operation of the unit and cannot rely on it to supplement the operation of the distribution system. When the Company would choose to run the unit does not necessarily coincide with when the owner would run it. Many factors can affect a customer's desire to run its unit. For example, as MeadWestvaco noted, a customer's business requirements would supercede the requirements of the utility grid.

Commenters also recommend that distribution companies implement a transparent planning process, and recommend that the Department require distribution companies to report on viable DG locations. MTC p.18, United Technologies p. 6, Real Energy p.16, GTI p. 5, NAESCO p. 4. This suggestion would compromise the confidentiality of sensitive customer information, because it would contain information from which it would be easy to derive peak load and data information for specific customers. In the Department's competitive markets initiative docket, D.T.E. 01-54, the Department acknowledged the confidentiality of this type of information, and does not allow the distribution companies to provide it to licensed competitive suppliers without a customer's authorization. D.T.E. 01-54-A, p. 14, footnote 7.

Some commenters recommend that distribution companies pay DG owners subsidies or credits in specific areas and/or implement pilots for distributed generation instead of improving the distribution infrastructure. Aegis Energy p. 4, Stone & Webster p.6, United Technologies p. 8, Ingersoll Rand p. 6, Fitchburg Gas & Electric p.10, GTI p. 5, NAESCO p. 4, Capstone Turbine Corporation p.10, Plug Power p. 6. Mass. Electric's Brockton pilot, described in Mass. Electric's initial comments, as well as an RFP pilot in New York looking at DG in lieu of distribution system upgrades, should provide valuable information on this subject.

As discussed in Mass. Electric's initial comments, Mass. Electric is in the midst of a load curtailment pilot in Brockton to determine the potential of deferring a $1.2 million substation expansion at the Belmont St. substation in Brockton, Massachusetts, using a localized interruptible rate concept. The program has called interruptions July 3rd, July 23rd, August 13th and 14th. Preliminary results of the July interruptions show an average reduction of 635 kW and 860 kW, respectively. Exhibit 4 shows the baseline and actual loads for interruptions on July 3rd and 23rd . The goal in the first year of the Brockton Pilot was a consistent 950 kW reduction, and/or to limit the load at the substation to an artificially limited 45 MW. (In reality, the substation has a limit of 50 MW, but in case of poor performance in the pilot the Company wanted to assure the pilot did not threaten reliability for the customers in the area served by the substation). The Brockton Pilot has no restrictions on how customers reduce their load requirements from the distribution system. Most customers were planning on curtailing load as well as adding enhancements to existing building management systems to provide relatively transparent load shedding within the facility; however, load reduction through operation of DG would also qualify under the pilot.

In addition, as part of a pilot project in New York, Mass. Electric's affiliate, Niagara Mohawk issued an RFP for DG in lieu of distribution system infrastructure improvements on July 1st, with bids due September 3rd for two Niagara Mohawk locations with a need of 20 MW each. The results of the RFP process should provide valuable information to assess the potential for using DG as a distribution planning tool.

In summary, distribution companies have considered the role of distributed generation in their planning process for many years. The challenge is finding a solution that is as inexpensive as wires technology over the life cycle of the investment. Both the Brockton and New York pilots should provide valuable information on the ability of DG (1) to perform when called and (2) to perform against distribution investments. The Department does not need to order these experiments when they are proceeding on a voluntary basis. Distribution planners will employ the results of these experiments to provide low cost, reliable solutions going forward.

IV. Conclusion

For the reasons set forth herein, Mass. Electric recommends that the Department (1) establish a collaborative working group to develop consistent state-wide interconnection policies and procedures, (2) direct the distribution companies to propose standby or backup rates which provide for various levels of service, as set forth in Mass. Electric's initial and reply comments, or in the alternative, establish a collaborative working group to develop the framework for standby or backup rates, and (3)

Respectfully submitted,

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